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Performance of Water Injection in Oil Rim Reservoir Recovery Factor

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Abstract

This study examines the potential improvements in recovery factors in optimizing oil production from oil rim reservoirs through water injection and without water injection (i.e. primary production) scenarios in the development strategies of the oil rim reservoirs. A generic simulation model developed from ECLIPSE dynamic simulator was used as core representative of oil rim reservoirs to experiment production optimization with and without water injection. Reservoir data of permeability, oil rim thickness, fluid properties, m-factor, aquifer strength and process parameters sampled from the Niger Delta oil field were used and a placket-Burman Design of experiment (DOE) was used to give a central sensitivity results from the simulation runs. Recovery factors were obtained for the two different production scenarios: primary production and production under water injection. Regression analyses were carried out on the experimental results to generate proxy equations for recovery factor for the two production scenarios. It was observed that the use of water injection is irrelevant for oil rims with active water aquifer. However, water injection will increase the ultimate recovery of oil rim reservoirs under weak aquifer.

Keywords: *Oil rim reservoirs, recovery factor, water injection, primary production, simulation study*

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INTRODUCTION

Oil rim reservoir refers to a saturated reservoir with an oil column of limited thickness, overlain by a gas cap and underlain by an aquifer. Field development of such reservoirs are characterised with challenges due to the fact that the oil reserve is spread out in thin layers with small initial mobile thickness and the presence of huge overlaying gas cap and varying strength of underlying water. Oil rims with thickness less than 30-ft are usually considered technically and economically unattractive for development. Olamigoke reported that oil columns less than 30-ft thick have been developed; however the performance results have been mixed. The success of oil rim development requires careful management of a wide range of subsurface uncertainties and generally lengthy study efforts are needed to assess the technical and economic feasibility. The major factors controlling development are aquifer strength, permeability distribution, and reservoir geometry across the reservoir. Guidelines are therefore required for quick screening of oil rims for technical feasibility before embarking on detailed studies to determine optimum development strategies [1].

This work presents a generic dynamic simulation study. A generic simulation model has been developed to assess oil rim development strategies over several sub-surface parameters to provide a guide to oil rim performance and development strategies to experiment production optimization with and without water injection.

LITERATURE REVIEW

Understanding oil rim reservoir production dynamics is critical to successful development of thin oil rims. Thin oil rim development can be likened to the production of a large oil column towards the late end of its economic life when abandonment would be strongly considered. The two most important displacement mechanisms to displace oil from oil rims reservoir are:

1. Displacement of oil by water due to aquifer influx.
2. Displacement of oil by gas due to the expanding gas cap.

Sascha and Marc in their attempt to explain the concept of limiting oil rim movement, it was necessary to keep the two main drive mechanisms in pressure equilibrium [2]. This can be achieved as follows:

i. Increasing support to the least dominant drive mechanism. This can be achieved by supplying pressure support (injection) to either the gas cap or the aquifer.
ii. Decreasing support to the most dominant drive mechanism. This can be achieved by production from either the gas cap or the aquifer. A disadvantage of this method is the possibility that the reservoir pressure decline can become quite excessive.

Behrenbruch Identify three broad categories of hydrocarbon reservoir development: Primary recovery relates to using the natural energy of the reservoir to drive production. Secondary recovery relates to supplementing the natural drive with additional energy via water or gas injection. Tertiary recovery relates to injection of fluids to change the chemical or physical properties of the in-situ hydrocarbons [3].

Behrenbruch and Mason showed that oil recovery could be maximized from an oil rim reservoir with a small gas cap ($m<0.2$) by blowing down the gas cap during the initial production phase, provided a strong aquifer exists.

The essence of this strategy is to develop the gas cap first and then allow the oil rim to move to the crest of the reservoir that will be produced by the same Crestal gas cap well [3].

Vo and Sukerim discussed the parameters affecting thin oil column development: The main factors influencing the depletion strategy for oil rim development under gas gap and water drive support were identified as; oil rim thickness, permeability, gas cap size, aquifer strength, reservoir geometry, magnitude of bed dip and Oil viscosity. They also showed that horizontal wells in thin oil columns provide large drainage areas, more reserves and better recovery efficiency compared to vertical wells [4].

Thomas pointed out that lithology has a profound influence on the efficiency of water injection in a particular reservoir. Reservoir lithology and rock properties that affect injecting ability and success are: Porosity, Permeability, Clay content, net thickness.

In some complex reservoir systems, only a small portion of the total porosity, such as fracture porosity, will have sufficient permeability to be effective in water-injection operations [5].

Waqanhofer and Hatzignaton suggested that there would be a location within the oil zone at which both water and gas fluids cone simultaneously into the horizontal well. At this location, the pre-breakthrough time, cumulative oil production is maximized. They, therefore, developed correlations for predicting the time at which gas and water cone simultaneously into a horizontal well and the optimum location of the well with respect to water-oil and gas-oil contact [6].

Onwukwe et al. proposed semi-analytical models of estimating critical rate and optimum horizontal well placement to controlling coning tendencies in oil rim reservoirs [7]. The models were developed through semi-analytical analysis of applying equation and the principle of Nodal analysis.

The developed models can be used as a tool to make a first pass assessment in the development of oil rim reservoirs anticipated to experience water and/or gas coning during production [8].

METHODOLOGY

A generic oil simulation study was carried out by building a dynamic box model of an oil rim with the geological properties populated across the grid using an Eclipse Simulator. A matched PVT model of representative fluid was used and a producer and an injector wells were situated in the model accordingly to study the primary production case and the water injection scenario. The range of parameters used in the model is presented in Table 1.

Table1: *Reservoir Parameter Range of Factors Investigated.*

RIM PARAMETERS	Lowest	Median	Highest
K_v/K_h	0.001	0.01	0.1
Permeability, mD	100	1000	2000
Oil Rim Thickness, ft	20	34	60
Oil Viscosity, cp	0.4	1	2
Derived from API,degree	39.18	32.65	24.16
Oil Rate,stb/day	1300	2500	5000
m-factor (dimensionless)	0.268	1	4.73
K_{rw}	0.15	0.3	0.45
S_{or}	0.15	0.23	0.3
Horizontal well length, ft	1200	1800	2400
Aquifer factor, dimensionless	2	7	15
Height below GOC	2 cells beneath	3 cells beneath	4 cells beneath

The simplistic reservoir model used in the simulation was built using oil rim reservoir data collected across several oil fields in the Niger Delta. An average porosity value of all the reservoirs is used in the models. Permeability and anisotropy ratio are varied in the analysis. The average gas zone thickness and thin oil zone are varied according to the design objective. The target reservoir has a strong aquifer support which is a variable in the study. The simulation model is summarized in Figure 1.

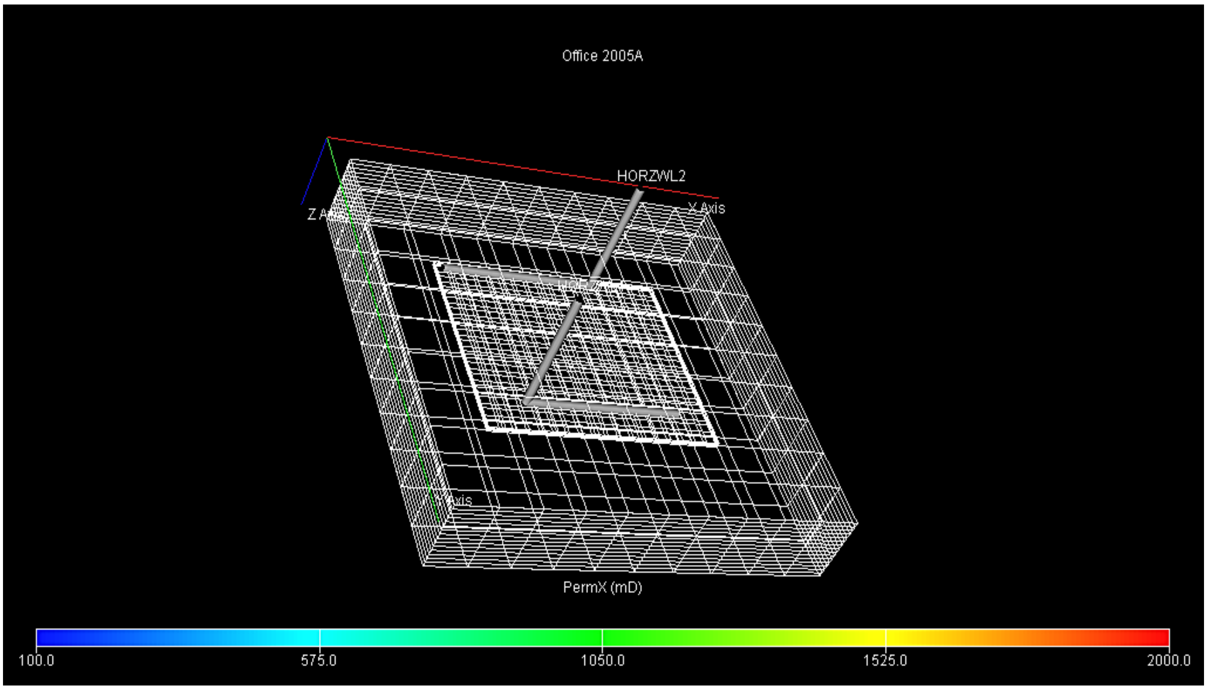

Fig 1: *A 3-D Box Model with Refined Grid Cells around the Well Bore.*

Model Geometry Grid Structure

The geometry of the model has been fixed at 600 x 600ft in the x and y directions, which are considered sufficiently large to avoid boundary or edge effects impacting the recovery process and results. The thickness of the model is varied depending on the required thickness of rim to be studied. No shale barriers or faults have been introduced in the model. The simplistic geological description is intended to allow focus on the parameters effect on the displacement of oil from the oil rim reservoir and prevent the influence of localized flow barriers.

Fluid Modeling (PVT)

Oil and gas properties are generated using Eclipse PVT$_i$. The reservoir pressure was set to below bubble point pressure to help model gas flow to and from the gas cap. API gravity and Specific Gas Gravity are used as input variables. Zero N_2, H_2S or CO_2 contamination is assumed. The PVT correlations were used to obtain closest representative models of the provided PVT data.

Well Description

Two horizontal oil production wells were placed centrally within the oil rim section of the models for simulating the primary production case and one of the wells was converted to an injection well to simulate the water injection scenario. This arrangement is aimed at obtaining an accurate relationship between recovery and the reservoir parameters. The well length is a variable in the analysis. Prosper of IPM was used to build a wellbore model to take account of the pressure drop along the horizontal section of the well.

The constraints used in the generic oil rim model are:

- Minimum BHP of 1200 psi
- Maximum allowable water cut of 90%
- Simulation time of 30 years

Optimum Injection Rate

Using the model described above, a thickness of 40ft and the initialization parameters given above, a sensitivity analysis was carried out to obtain suitable injection rate that will be used throughout the experiment.

Table 2 shows the result of the sensitivity analysis. The rate with the highest incremental recovery, i.e., 2000stb/d, was selected and used as the optimum injection rate for the experiments.

Modeling Response Using Design of Experiment

Plackett-Burman Experimental Design (ED) technique was used to capture the impact of a range of sub-surface uncertainty on oil rim recovery. To increase the strength of the linear screening, the folded Plackett-Burman with a center point run consisting of all mid case was added (run 14), and an extra run to define the maximum outcome was also introduced (run 13) (Table 3).

Table 2: *Sensitivity Study on the Rate of Injection.*

Injection Rate (STB/D)	Cumulative Production (STB)	Increamental Oil Recovery (STB)
1000	1.2373E+07	-
1500	1.2545E+07	172000
2000	1.2719E+07	174000
2500	1.2720E+07	1000
3000	1.2721E+07	1000
3500	1.2742E+07	21000

Table 3: *An 11 Parameter Placket-Burman Design.*

Run No.	H_o	m_{fac}	Aq_{fac}	K_h	K_v/K_h	Sor	API	H_{GOC}	L_H	Q	K_{rw}
1	60	4.73	2	2000	0.1	0.3	24.16	24.00	1200	5000	0.15
2	60	0.268	15	2000	0.1	0.15	24.16	48.00	2400	5000	0.45
3	20	4.73	15	2000	0.001	0.15	24.16	8.00	1200	5000	0.45
4	60	4.73	15	100	0.001	0.15	39.18	48.00	2400	5000	0.15
5	60	4.73	2	100	0.001	0.3	24.16	48.00	2400	1300	0.45
6	60	0.268	2	100	0.1	0.15	39.18	48.00	1200	5000	0.45
7	20	0.268	2	2000	0.001	0.3	39.18	8.00	2400	5000	0.45
8	20	0.268	15	100	0.1	0.3	24.16	16.00	2400	5000	0.15
9	20	4.73	2	2000	0.1	0.15	39.18	16.00	2400	1300	0.15
10	60	0.268	15	2000	0.001	0.3	39.18	48.00	1200	1300	0.15
11	20	4.73	15	100	0.1	0.3	39.18	8.00	1200	1300	0.45
12	20	0.268	2	100	0.001	0.15	24.16	8.00	1200	1300	0.15
13	60	4.73	15	2000	0.1	0.3	39.18	48.00	2400	5000	0.45
14	34	1	7	1000	0.01	0.23	32.65	20.40	1800	2500	0.3

Proxy Equations

Regression analysis carried out on the sets of data in Table 6, with the recovery factor (RF) for both the primary recovery case and the water injection case as dependent variable respectively.

Table 4: *Coefficients for RF_{pr}.*

COEFFICIENTS	VALUES
a_o	12.4957
a_1	-0.0242
a_2	-2.3215
a_3	0.6656
a_4	0.0062
a_5	-168.1395
a_6	-48.0784
a_7	0.3195
a_8	0.5886
a_9	0.0020
a_{10}	0.0001
a_{11}	6.0808

The proxy model for estimating the RF for both primary and water injection case are generated respectively as:

$$RF_{pr} = a_o + a_1(H_o) + a_2(m_{fac}) + a_3(Aq_{fac}) + a_4(K_h) + a_5\left(\frac{K_v}{K_h}\right) + a_6(S_{or}) + a_7(API) + a_8(H_{GOC}) + a_9(L_H) + a_{10}(Q) + a_{11}(K_{rw}) \quad (1)$$

$$RF_{wi} = b_o + b_1(H_o) + b_2(m_{fac}) + b_3(Aq_{fac}) + b_4(K_h) + b_5\left(\frac{K_v}{K_h}\right) + b_6(S_{or}) + b_7(API) + b_8(H_{GOC}) + b_9(L_H) + b_{10}(Q) + b_{11}(K_{rw}) \quad (2)$$

where a_0, a_1, a_2, a_3, a_4, a_5, a_6, a_7, a_8, a_9, a_{10}, a_{11} and b_0, b_1, b_2, b_3, b_4, b_5, b_6, b_7, b_8, b_9, b_{10}, b_{11} are respective coefficients. See coefficients values in Tables 4 and 5, respectively.

Table 5: *Coefficients for RF_{wi}.*

COEFFICIENTS	VALUES
b_o	26.6537
b_1	–0.7115
b_2	–3.8369
b_3	–0.4421
b_4	0.0044
b_5	–136.3918
b_6	4.3256
b_7	0.3472
b_8	1.1880
b_9	–0.0031
b_{10}	0.0040
b_{11}	5.4412

RESULTS AND DISCUSSION

For the eleven variables of the Placket-Burman design, 14 flow simulation runs were made for both primary recovery case and water injection case. The results of the simulation are shown in Table 6 below.

Table 6: *Simulation Results of RF for Primary Recovery and Water Injection Scenarios.*

Run No.	H_o	m_{fac}	Aq_{fac}	K_h	K_v/K_h	S_{or}	API	H_{GOC}	L_H	Q	K_{rw}	RF_{pr} (%)	RF_{wi} (%)
1	60	4.73	2	2000	0.1	0.3	24.16	24.00	1200	5000	0.15	**7.5346**	**15.2578**
2	60	0.268	15	2000	0.1	0.15	24.16	48.00	2400	5000	0.45	**53.7924**	**53.8457**
3	20	4.73	15	2000	0.001	0.15	24.16	8.00	1200	5000	0.45	**32.0691**	**32.4563**
4	60	4.73	15	100	0.001	0.15	39.18	48.00	2400	5000	0.15	**50.8697**	**45.0356**
5	60	4.73	2	100	0.001	0.3	24.16	48.00	2400	1300	0.45	**30.3506**	**32.0875**
6	60	0.268	2	100	0.1	0.15	39.18	48.00	1200	5000	0.45	**32.7500**	**57.7593**
7	20	0.268	2	2000	0.001	0.3	39.18	8.00	2400	5000	0.45	**38.4498**	**61.0678**
8	20	0.268	15	100	0.1	0.3	24.16	16.00	2400	5000	0.15	**12.0689**	**32.5479**
9	20	4.73	2	2000	0.1	0.15	39.18	16.00	2400	1300	0.15	**16.8278**	**19.5689**
10	60	0.268	15	2000	0.001	0.3	39.18	48.00	1200	1300	0.15	**62.5878**	**59.7560**
11	20	4.73	15	100	0.1	0.3	39.18	8.00	1200	1300	0.45	**3.9344**	**3.9689**
12	20	0.268	2	100	0.001	0.15	24.16	8.00	1200	1300	0.15	**29.4236**	**36.1945**
13	60	4.73	15	2000	0.1	0.3	39.18	48.00	2400	5000	0.45	**43.5345**	**42.5246**
14	34	1	7	1000	0.01	0.23	32.65	20.40	1800	2500	0.3	**24.8290**	**33.0357**

Figure 2 shows a comparative analysis of the simulation runs. Simulation runs number 1, 5,6,7,8,9,12 and 14 has a relative increment respectively in the recovery factor of the oil rim reservoir when water injection was introduced. The increment in RF due to water injection results from low value of the Aquifer factor (Aq_{fac}), that is, weak aquifer strength. The injected water therefore recharged the weak aquifer to help stimulate recovery from the oil rim reservoir, hence the increment in the recovery factor. However, oil rim reservoirs with high Aquifer factor, i.e strong aquifer strength, may not require water injection. Due to the strong aquifer strength which recharges itself, water injection may not necessarily enhance the recovery factor as shown in simulation runs number 2, 3, 4, 10, 11 and 13 in Figure 2.

Proxy Model Validation

The proxy models for estimating RF_{pr} and RF_{wi} were compared with that generated from the simulator. Figure 3 shows that the RF_{pr} estimated from the proxy model compares favourably with that of the simulation study with an R Square of 0.9475 and standard error of 10.2580. Also, Figure 4 shows a more favourable match in the RF_{wi} estimated from the proxy model and that generated from the simulation study with an R Square of 0.9732 and standard error of 7.1881.

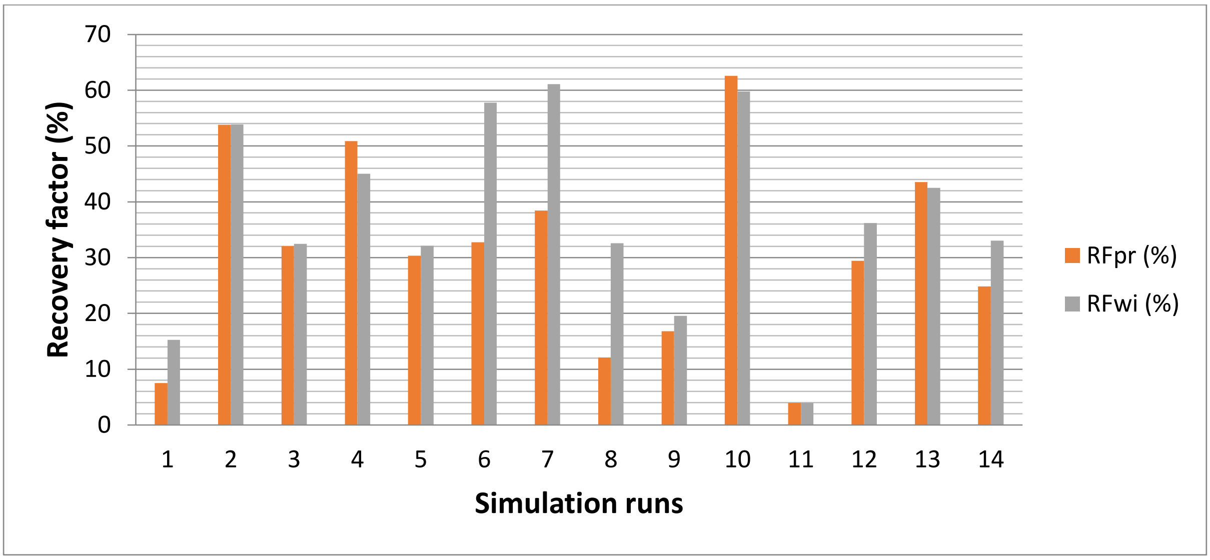

Fig. 2: *Analysis of RF from Primary Production (RF_{pr}) and Water Injection (RF_{wi}) Scenarios.*

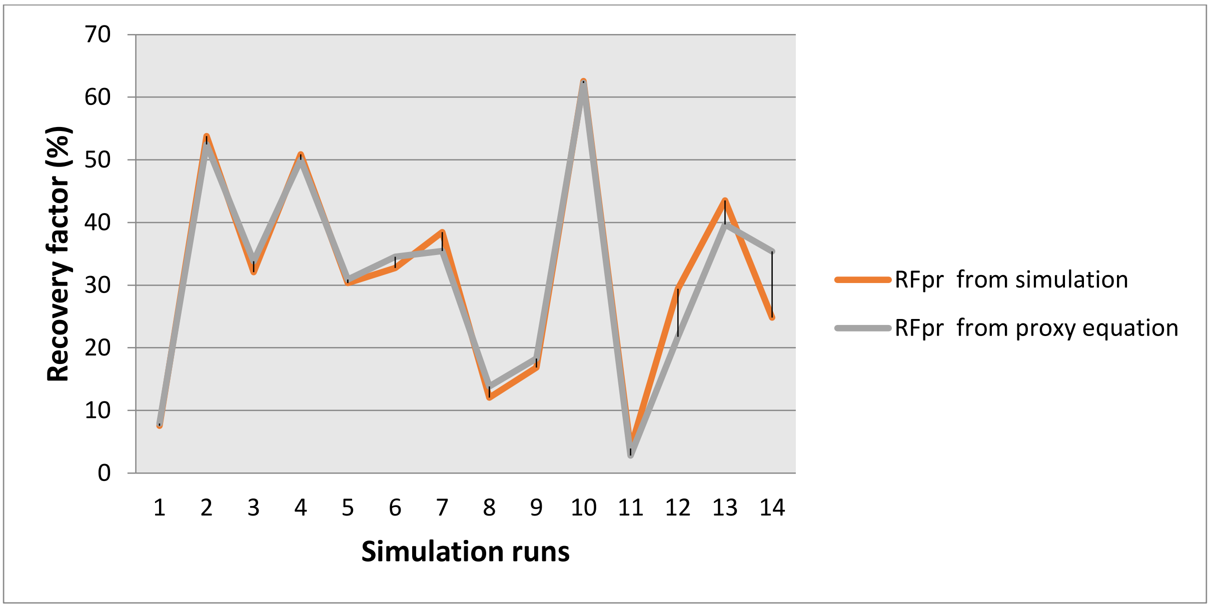

Fig. 3: *RF_{pr} Comparison from Simulation and Proxy Equation.*

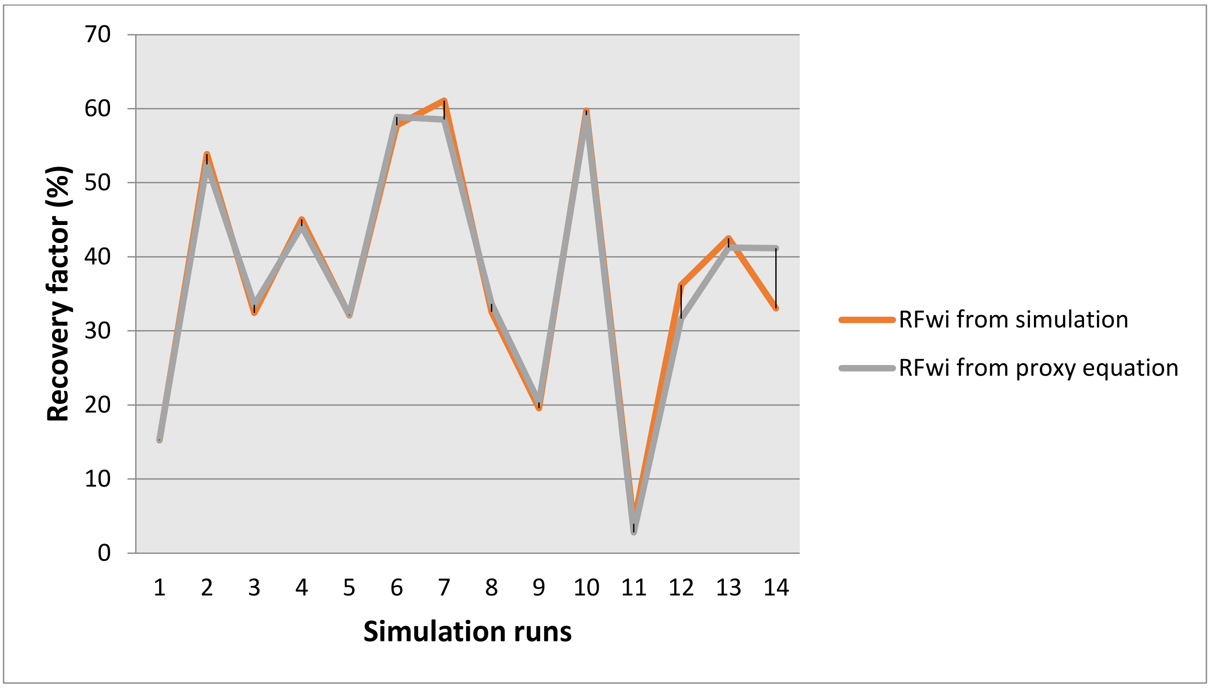

Fig. 4: *RF_{wi} Comparison from Simulation and Proxy Equation.*

CONCLUSIONS

On the basis of the study, following conclusions have been drawn:

1. A generic simulation model has been developed which can be used as a screening tool to make a first pass assessment of the likely recovery factor from oil rim reservoirs of 20–60-feet range.
2. Application of water injection to oil rim development will increase the ultimate recovery under weak aquifer.
3. In an oil rim reservoir where the aquifer is active, injection of water contributes nothing. This is because the aquifer volume marred the effect of the injected water.
4. During injection of water into oil rims with weak aquifer, attention should be focused on injection rate to avoid flux of injected water into the oil rim which could cause unstable displacement of oil.

Model Limitations

The developed model has the following weaknesses:

A. Applicability is limited to the range of data source.
B. Based solely on simulation data-
C. No validation with production data.

NOMENCLATURE

API:	American Petroleum Institute
Aq_{fac}:	Aquifer Factor
DOE:	Design of Experiments
H_{GOC}:	Height above Gas Oil Contact
H_o:	Height of the Oil Column
L_H:	Horizontal Well Length
k_h:	Horizontal Permeability
$k_{rw:}$	Relative Permeability to water
k_v/k_h:	Ratio of Vertical Permeability to Horizontal Permeability
k_v:	Vertical Permeability
m_{fac}:	Gas cap factor
OIIP:	Oil Initially In Place
PVT:	Pressure, Volume and Temperature
Q:	Oil Flow Rate
RF:	Recovery Factor
RF_{pr}:	Recovery Factor for Primary recovery case
RF_{wi}:	Recovery Factor for water injection case
S_{or}:	Residual Oil Saturation
WOC:	Water Oil Contact
WOR:	Water Oil Ratio
3D:	Three Dimensional

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